Docket No. 00-0259
ICC Staff Exh. 1.0 Redacted

DIRECT TESTIMONY

OF

RICHARD J. ZURASKI

SENIOR ECONOMIST

ILLINOIS COMMERCE COMMISSION

ENERGY DIVISION—POLICY SECTION

Docket No. 00-0259

Commonwealth Edison Company

Petition for expedited approval of implementation of a market-based alternative tariff, to become effective on or before May 1, 2000, pursuant to Article IX and Section 16-112 of the Public Utilities Act

April 18, 2000

Redaction of confidential information shown as XXXX.

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1. Witness Qualifications

Q. State your name and business address.

A. Richard J. Zuraski, Illinois Commerce Commission, 527 East Capitol Avenue, P.O. Box 19280, Springfield, Illinois, 62794-9280.

Q. By whom are you employed and in what capacity?

A. I am employed as a Senior Economist in the Illinois Commerce Commission's Energy Division—Policy Section.

Q. What are your responsibilities within the Energy Division—Policy Section?

A. I provide economic analyses and advise the Commission and other staff members on issues involving the gas and electric utility industries. I review tariff filings and make recommendations to the Commission concerning those filings. I provide testimony in Commission proceedings. In selected cases, I sometimes act as an assistant to the Commission or to hearing examiners.

Q. State your educational background.

A. I graduated from the University of Maryland with a Bachelor of Arts degree in Economics. I obtained a Masters of Arts degree in Economics from Washington University in St. Louis. I completed other work toward a doctorate in economics from Washington University, but have not completed all requirements for that degree.

Q. Describe your professional experience.

A. Since December 1997, I have been a Senior Economist in the Policy Program of the Commission's Energy Division. I held the same position from February 1990 to December 1997, in the Commission's Office of Policy and Planning (prior to its incorporation into the Energy Division). Before that, I held positions in the Commission's Least-Cost Planning Program and Conservation Program. While employed by the Commission, I have testified in numerous docketed proceedings before the Commission. Prior to coming to the Commission in November 1987, I was a graduate student at Washington University, where I taught various courses in economics to undergraduate students in the Washington University night school and summer school.

2. Purpose of Testimony

Q. What is the purpose of your testimony?

A. First, I will provide some background on (a) the nature of the delivery services option for purchasing electric services on an unbundled basis, (b) the Power Purchase Option ("PPO"), and (c) the customer transition charge ("CTC") paid by delivery service and PPO customers under the Illinois Public Utilities Act ("Act"). Second, I will comment on the importance of the so-called "market value" ("MV") in the computation of PPOs and CTCs; the "market value" is a proxy for actual market prices of power and energy. Third, I will briefly describe the nature of the Commission's authority to modify a utility's proposal to implement a non-NFF alternative mechanism for computing market values. Fourth, I describe Commonwealth Edison Company's ("ComEd's") proposal for a "market-based alternative tariff" that would be used, in lieu of the Neutral Fact Finder process, as the basis for computing MVs for ComEd's own PPOs and CTCs. Fifth, I will attempt to assess certain elements of the ComEd proposal. Sixth, I will provide my recommendations.

3. Background on Delivery Services, the PPO, and CTCs

Q. Please describe the restructuring of the electric utility industry that has taken place in Illinois since 1997.

A. The Electric Service Customer Choice and Rate Relief Law of 1997, which became effective in December of 1997, created Article 16 of the Act. That article required each electric utility in the State to file tariff sheets with the Commission that would enable retail customers located in the electric utility's service area to receive electric power and energy from suppliers other than the electric utility. That is, rather than purchase the gamut of traditional utility services from the utility as a single "bundled" package, customers would be able to purchase "delivery services" from the utility on an unbundled basis and purchase the power output of generators from other third-parties, such as other utilities, power marketers or generating companies. Among participants in ICC delivery service proceedings, these third-party entities, who are eligible to market power at retail in Illinois, have come to be known collectively as "retail electric suppliers" ("RESs"). This term includes, but is not limited to, Alternative Retail Electric Suppliers ("ARES") as that term is defined in the Act. Through the restructuring described above, delivery services remain regulated, but the business of supplying power at retail may be subject to a greater degree of competitive forces, as utilities and RESs vie for the patronage of consumers.

Q. Were utilities subject to competition from the outset of delivery services?

A. No. The Act did not subject utilities to the rigors of a potentially competitive marketplace without a transition period. For instance, during this transition period, utilities that have embedded costs of generation that are higher than what the market will bear are afforded opportunities to recover what might <u>otherwise</u> have been "<u>stranded</u>" costs through a non-bypassable "customer transition charge" ("CTC"). The CTC is applied to customers that switch from bundled either to unbundled delivery services or to the so-called Power Purchase Option ("PPO").

Q. What is the PPO?

A. The PPO is, in essence, a bundled service that a utility is required by the Act to offer if the utility chooses to impose a CTC. However, while the utility, under the PPO, continues to provide the entire panoply of traditional utility services as a single bundled package, the utility's PPO <u>charges</u> are unbundled into (a) a PPO administrative fee component, (b) a delivery services component, (c) a CTC component, and (d) a power and energy component. The charge(s) for the power and energy component are to be based on the same market values used in the computation of the CTC.

<u>4. The Importance of Market Values</u>

Q. What is the role of Market Value ("MV") in the CTC?

A. The Act specifies a basic formula for computing the CTC, which I simplify as follows:

$$\mathbf{CTC = BR - DSR - MV - mf}, \quad \text{where}$$

BR is the customer's or customer class' average bundled rate,

DSR is the customer's or customer class' average delivery services rate

MV is the market value (as adjusted for the load characteristics for the customer or customer class); and

mf is a "mitigation factor" applicable to the customer or customer class.

Hence, the MV is one of the components in the basic formula for computing the CTC. Although a specific rationale was not given in the Act for this formula, a clearly reasonable interpretation of the formula is that the CTC affords the utility an opportunity to continue recovering (during the transition period) the cost of generation resources included in the regulated bundled rate (i.e., BR - DSR) net of the price that the utility can obtain in the market for the output of its generation resources (i.e., MV) and also net of the so-called mitigation factor. The mitigation factor is defined in the Act and it varies somewhat by customer class and increases somewhat as the transition period progresses.

Q. What is the mitigation factor?

A. One might loosely refer to the **mf** as a "stretch factor," in that the utility must achieve cost savings of at least **mf** in order to at least fully recover the potentially stranded costs associated with restructuring. The mitigation factor is not subject to any regulatory examination by the ICC or any periodic reconciliation process, so utilities can significantly over-recover or under-recover their potentially stranded costs, depending upon how effectively utilities manage their costs and unearth and develop new revenue sources.

Q. What happens if the above CTC formula results in a negative number?

A. If the above formula results in a negative number, then the CTC is set to zero. In other words, utilities are permitted to recover otherwise stranded <u>costs</u>, but are not required to return any stranded <u>benefits</u> after they are allowed to enter the marketplace as an unregulated competitor.

Q. What does a delivery services customer pay for his electric services?

A. The delivery services customer pays to the utility the applicable set of delivery services rates ("DSRs") and the applicable CTCs, if any. The customer also pays to a RES a negotiated price for power and energy. If the MV used in the CTC formula is representative of actual prices being paid for power and energy in the retail market, then the amount that any given customer pays to the RES might be expected to be somewhere in the neighborhood of MV. However, the actual price of power and energy paid by any given customer is an unregulated contractual matter between buyer and seller and is not directly tied to the inputs into the CTCs. Hence, the MVs should only be considered a proxy or estimate of the actual market price, **P**, facing a typical customer, subject to some degree of error:

$$\mathbf{MV = P + error.}$$

Here, a positive **error** represents the MVs in the CTC being overestimated, while a negative **error** represents the MVs being underestimated.

Q. How does the total bill of the delivery services customer compare to the bundled rate?

A. Again using a simple model, and assuming that the CTC is positive, the delivery services customer pays the following:

Delivery Service Customer's Total Bill

$$\mathbf{= DSR + CTC + P}$$

= DSR + (BR - DSR - MV - mf) + P

= DSR + (BR - DSR - (P + error) - mf) + P

= BR - mf - error.

Hence, the delivery services customer would pay a total amount equal to the bundled rate minus the mitigation factor minus the error in the MV estimate of the applicable market prices. As long as the **error** in the market value estimate that is used in the CTC is positive (or, if negative, at least not as great in magnitude as the mitigation factor), then the customer will be able to save by switching to delivery services at market price, **P**.

Q. **If the MV is sufficiently under-estimated, what happens to the customer's total bill?**

A. If **MV** is underestimated enough, such that **-error - mf > 0**, then the customer's total bill would be greater under delivery services than under the traditional bundled service arrangement.[1] Presumably, few, if any, customers would choose to pay more for basically the same commodity. Hence, a sufficiently underestimated MV will prevent customers from switching to a RES. Thus, even though a RES may be able to supply electricity to a retail customer at a rate that is less than the true market value of power and energy and less than the utility's own embedded generation costs, an underestimated MV in the CTC can prevent a RES from showing a customer any savings relative to the bundled rate. Basically the same problem can prevent a RES from showing a customer any savings relative to the PPO, as well.

[1] For example, suppose the **mf** is 0.73 cents per kwh and the **error** is -0.94 cents per kwh (the negative sign indicating that the market prices have been ***under***-estimated. In that case, **-error - mf** = - (-)0.94 - .73 = +0.94 - 0.73 = 0.21 cents per kwh. Hence, the Delivery Service Customer's Total Bill in this hypothetical example would be higher than the bundled rate by 0.21 cents per kwh.

Q. Do customers and RESs always benefit when, all else constant, the MV rises?

A. No, not all customers benefit from a rise in MV. On the one hand, a prospective delivery service customer is apt to prefer an over-estimated market value, since this leads to a decrease in the CTC without affecting the actual market price that the customer pays to a RES. Overestimated MVs also mean that a RES, all else constant, would be in a better position to offer savings to any given customer, relative to the bundled rate or the PPO. In contrast, sufficiently under-estimated MVs could render it impossible for some or all RESs to bring savings to customers, as suggested by footnote 1. Hence, one could argue that overestimating MVs could stimulate more competitive entry, while underestimating MVs could retard the development of competitive entry, during the transition period.

On the other hand, <u>if a particular customer's cheapest option is **not** to be a delivery services customer, but rather is to be a **PPO** customer, then the customer does not necessarily benefit from an increase in the CTC's MVs.</u> To see this, one must first understand what a PPO customer pays for electric service.

Q. What does a PPO customer pay for electric services?

A. The PPO customer pays to the utility the applicable PPO administrative fee ("Fee"), the applicable set of delivery services rates (DSRs), the applicable transition charges (CTCs) and the applicable MVs (the same MVs used to compute the CTC). Hence, unlike the delivery services customer that purchases power and energy from a RES, the customer taking the PPO faces the same MVs as positive charges for power and energy that are included in the customer's CTC as credits.

Q. If the PPO customer faces the same MV as both a positive charge and a credit, does the MV merely "cancel"?

A. Again using a simple model, the MVs, as well as the DSRs, cancel. That is, under our simplified formula, the PPO pays:

$$\mathbf{PPO\ Total\ Bill}\,\Big|_{CTC>0}$$

$$\mathbf{= Fee + DSR + MV + CTC}$$

$$\mathbf{= Fee + DSR + MV + (BR - DSR - MV - mf)}$$

$$\mathbf{= Fee + BR - mf}$$

Hence, the MV appears to be irrelevant to the calculation of PPO total bill. However, one must remember that the above is a simplified view of the rate structure. A more detailed accounting would show that the DSR as a positive charge may consist of a several different components, but, as a credit within the CTC, the DSR has been reduced to a single number. Similarly, while the MV as a positive charge in the PPO may consist of several different MVs that vary between on-peak and off-peak, summer and winter (or even more finely disaggregated time periods), as a credit within the CTC, these MVs have been reduced to a single number. Because of these factors, the simple equation above should be viewed as an abstraction. However, the simple equation nevertheless shows the tendency (particularly for the average customers within each of the rate classes) of the MVs to cancel as the MVs essentially are both added and subtracted in the customer's total PPO bill . Furthermore, particularly in this case involving ComEd, there is a significant difference in the effect of MV increases when the CTC is already zero or when the MV increase causes the CTC to go to zero.

Q. What happens to the PPO when the CTC is zero?

A. The Act does not appear to require utilities to provide the PPO unless the customer is paying CTCs. Notwithstanding that provision of the Act, my understanding is that ComEd will continue to offer a PPO to a customer as long as ComEd has a Rate CTC in effect that is applicable to that customer, even if the actual numerical value of the CTC for the customer is zero. In that instance, the PPO total bill in our simplified model would be as follows:

$$\textbf{PPO Total Bill}\,\Big|_{CTC=0} = \textbf{Fee} + \textbf{DSR} + \textbf{MV}.$$

Q. How does the PPO Total Bill with a CTC of zero compare to the PPO with a positive CTC?

A. Since we are concerned with market value in this case, assume that the difference between the two CTCs is due to differences in market value assumptions. Using the simple model of the CTC, from page 4 above, the fact that a CTC is zero implies that the CTC formula results in a number less than or equal to zero:

$$0 \geq \textbf{BR} - \textbf{DSR} - \textbf{MV} - \textbf{mf} = \textbf{CTC}$$

$$\textbf{DSR} + \textbf{MV} \geq \textbf{BR} - \textbf{mf}.$$

Adding the PPO **Fee** on both sides of the last inequality preserves the inequality and helps to show the relationship between the PPO with a zero CTC and a PPO with a positive CTC:

$$\textbf{PPO Total Bill}\,\Big|_{CTC=0} = \textbf{Fee} + \textbf{DSR} + \textbf{MV}$$

$$\geq$$

$$\textbf{Fee} + \textbf{BR} - \textbf{mf} = \textbf{PPO Total Bill}\,\Big|_{CTC>0}$$

Hence, in the simple model of the PPO, the PPO customer does not necessarily benefit from an increase in the MV.

Q. How can a zero CTC be interpreted?

A. Neglecting the mitigation factor (or assuming that the CTC formula would have been less than **-mf**) and assuming that the "market value" used in the CTC is a reasonably accurate measure of the actual prices of power and energy prevailing in the market, a zero CTC implies that the average customer in the class is already getting a bargain relative to the market. That is, rewriting the above inequality, without the mitigation factor:

$$\mathbf{BR} \leq \mathbf{DSR + MV} \qquad \textit{(neglecting the mf).}$$

Hence, for some customers for whom the CTC is zero, the best deal in town may be the bundled rate. However, for these same customers, the PPO may constitute an even <u>better</u> deal as long as the MV is sufficiently underestimated that a positive CTC remains. In that instance, the PPO can be used to generate a savings approximately equal to the mitigation factor (net of the PPO administrative **Fee**).

Q. Are there any other reasons why a customer may not be able to save by switching to delivery services and taking service from a RES when the MV is either accurate or over-estimated relative to actual market prices and a positive CTC is in place?

A. Yes. There is no reason to expect all RESs to be equally endowed with resources, to have the same abilities to manage quantity and price risks, to have comparable aggregations of loads, or, more generally speaking, to have the same costs. Hence, <u>some</u> RESs will be unable to recover their costs, even if those costs fall below the utility's embedded generation costs, since the RES's costs must also fall below the the MV to remain competitive with the utility's PPO or bundled rates. Furthermore, by the time that a RES knows that a customer is switching to delivery services, once-accurate averages of market prices may be obsolete and under-estimates of the more current state of affairs. Also, there is no reason to expect that all customers will impose the same per unit cost on RESs. The CTC's MVs may be differentiated by class in order to capture some of these differences, but there is no guarantee that all customers can be profitably served, even if the CTC's MVs are reasonably good estimates of the average market prices prevailing in the market during some relatively relevant time period(s). There is no single set of prices that has an undeniable claim on being the rightful "Market Value."

5. The Commission's Authority to Modify a Utility's Proposal to Implement a Non-NFF Alternative Mechanism for Computing Market Values

Q. Under what authority may the Commission approve a mechanism for computing market values like the mechanism proposed by ComEd?

A. Section 16-112 (a) states that:

> The market value to be used in the calculation of transition charges as defined in Section 16-102 shall be determined in accordance with either (i) a tariff that has been filed by the electric utility with the Commission pursuant to Article IX of this Act and that provides for a determination of the market value for electric power and energy as a function of an exchange traded or other market traded index, options or futures contract or contracts applicable to the market in which the utility sells, and the customers in its service area buy, electric power and energy, or (ii) in the event no such tariff has been placed into effect for the electric utility, or in the event such tariff does not establish market values for each of the years specified in the neutral fact-finder process described in subsections (b) through (h) of this Section, a tariff incorporating the market values resulting from the neutral fact-finder process set forth in subsections (b) through (h) of this Section.

Thus, the Commission may approve a mechanism such as the one proposed by ComEd, but, in the absence of such a mechanism, the default is to rely upon the NFF process for the derivation of the market values to be used in the calculation of transition charges.

Q. Does the Commission have authority to modify a utility's proposal to replace the NFF with an alternative method?

A. With respect to such alternative methods for computing market values, Section 16-112(m) states that:

> The Commission may approve or reject, or propose modifications to, any tariff providing for the determination of market value that has been proposed by an electric utility pursuant to subsection (a) of this Section, but shall not have the power to otherwise order the electric utility to implement a modified tariff or to place into effect any tariff for the determination of market value other than one incorporating the neutral fact-finder procedure set forth in this Section. Provided, however, that if each electric utility serving at least 300,000 customers has placed into effect a tariff that provides for a determination of market value as a function of an exchange traded or other market traded index, options or futures contract or contracts, then the Commission can require any other electric utilities to file such a tariff, and can terminate the neutral fact-finder procedure for the periods covered by such tariffs.

Hence, the Commission apparently has the authority to modify ComEd's proposed methodology for computing market values, but ComEd can reject the Commission's modifications and rely instead on the NFF market values for purposes of computing transition charges.

6. Description of ComEd's Market Index ("MI") Alternative to the NFF's Market Values

Q. Please summarize the ComEd proposal for an MI alternative to the NFF's market values.

A. Since ComEd's petition and tariff sheets speak for themselves, I will keep my description of the proposal brief. ComEd's proposal is quite similar to the proposal that it made last year, roughly at the same time of the company's initial delivery services tariff filing. However, there are some differences, most notably in the source of on-peak price data and the manner in which prices are shaped to account for correlation between hourly loads and hourly market prices. Some features of the proposal include:

- ComEd proposes to compute market values twice per year for an Applicable Period A and an Applicable Period B, respectively. (In contrast, the NFF schedule includes one calculation per year). Depending on when a customer begins taking delivery service or PPO service, the customer would use either the Applicable Period A or the Applicable Period B prices. Both Applicable Periods A and B end each May, at which point existing delivery service and PPO customers would move to the next year's computation of Applicable Period A MVs and CTCs.
- MVs would be based on two sets of market price observations:
    - For on-peak prices, ComEd would utilize screen prints from two electronic trading platforms for Into-ComEd firm power: Altrade and Bloomberg Powermatch. The Applicable Period A on-peak prices to be determined each spring would be based on forward contracts for the next June through May (twelve-month) period. The Applicable Period B on-peak prices to be determined each summer would be based on forward contracts for the next September through May (nine-month) period.

    - For off-peak prices. ComEd would utilize the most recent historical price data available from Power Markets Week Daily Price Report.

- Customers that were taking PPO or delivery services by May 1, 2000 would be eligible to retain their existing PPO-NFF MVs and CTCs through December 31, 2000 or the end of their PPO contract, whichever comes first. All delivery service and PPO customers that begin service after May 1, 2000 would be subject to the MVs and CTC of the proposed MI. After December 2000, all customers would be subject to the proposed MVs and CTCs of the proposed MI.

7. Assessment of the ComEd proposal for a Market Index Alternative to the NFF

7.1. On-Peak and Off-Peak Price Data Sources

Q. Do you have any concerns about ComEd's proposed use of Altrade and Bloomberg Powermatch on-peak price data?

A. Yes. In my review of the workpapers associated with the Altrade and Bloomberg Powermatch data, it became clear that the vast majority of data did not represent actual wholesale trades (where there has been a meeting of the minds between buyer and seller); rather, the vast majority of the data represent the midpoints of the highest bids and lowest offers of potential buyers and sellers of power, respectively. For example, for the Altrade data, there were a total of XXX data points, X of which were the prices of actual trades that took place, while the remaining XXX were the midpoints of bid/ask spreads. For the Bloomberg Powermatch data, there were a total of XXX data points, X of which were the prices of actual trades that took place, while the remaining XXX data points were the midpoints of bid/ask spreads. Hence, roughly XXX percent of the data from Altrade and Bloomberg Powermatch consists of the prices of actual trades that have taken place.

Q. Why is the preponderance of bid/offer midpoints versus actual trade prices of concern?

A. Clearly, the lack of trades is an indication that bidders are not reaching a meeting of the minds on Altrade and Bloomberg Powermatch. Presumably, most of their actual trading is occurring somewhere else. From the Altrade and Bloomberg Powermatch data, themselves, I do not know how to determine the relative distance between real market prices and the highest bids on the one hand, and the lowest offers on the other hand. For example, hypothetically, on an afternoon when the highest bid on Altrade is $147 and the lowest offer is $157, should one infer that market participants, somewhere outside of Altrade, are making actual trades at $152 (the midpoint), as ComEd's methodology would assume, or at $148 or $156 or some other number within the spread (or even outside the spread)? The validity of bid/offer spread midpoints is ambiguous.

If the spreads between bids and offers were relatively small, then that might endow the data with some additional confidence. In this regard, I would note that the Altrade spreads vary between X% of their midpoints and XX% of their midpoints, and average around X% of their midpoints. The Bloomberg Powermatch spreads vary between X% of their midpoints and XX% of their midpoints, and average around X% of their midpoints. By way of comparison, in looking at the off-peak price data used in the ComEd's proposal, where all the data represent prices of actual trades reported to Power Markets Week Daily

Price Report, the high minus low price spreads vary between X% of their midpoints and XX% of their midpoints, and average around X% of their midpoints.

In addition, I would note that the Altrade and Bloomberg Powermatch figures may partially corroborate each other because the average percentage difference in their midpoints is less than XXX%. For any month, the average percentage difference is as high as XXXX% and as low as XXXX%. For any day, a percentage difference of XXX% constitutes the 99th percentile of the entire array of XXX observations (where each observation consists of values selected from both Bloomberg and Altrade for that day; hence, when applicable, the averaging of morning and afternoon bid/ask midpoints for each of the two services had already taken place). The fact that the Altrade and Bloomberg figures are so close might lead one to believe that they both reflect the same thing—like some other market where parties are actually making real deals. However, I would not leap to that conclusion, in this instance, given some of the facts revealed in the following question and answer.

Q. Are you concerned with the possibility of "manipulation" of the Altrade and Bloomberg Powermatch bids and/or offers?

A. Yes. For example, I am somewhat concerned that ComEd may dominate the ComEd hub, which may enable ComEd to present artificially low bids (to buy). If nobody else is bidding to buy (or seriously bidding), then ComEd's "low" bid may nevertheless be the observed high bid of the snapshot when MVs are supposed to be harvested from these electronic platforms. To begin investigating this potential, I inquired of ComEd in a data request (number 6c) about a particular observation from Altrade:

> Please show the complete list of bids and offers during the 1-Mar-00 3:15:00 PM snapshot, for the Into ComEd Jul-Aug00 5x16 Peak contract, and, within that list, indicate all bids and offers that were made by ComEd.

In response, ComEd indicated that there was one bid and one offer and they were both made by ComEd. In addition, Staff Data Request 13 asked ComEd to specify the portion of bids (and offers) for Into ComEd contracts that were made by ComEd during the period February 24, 2000 through March 22, 2000. In response, I learned that the vast majority of both bids and offers were made by ComEd. The complete response to the above-mentioned data request is reproduced in Staff Exh. 1.1. It shows that for some contracts delivery periods, ComEd represented all bids and all offers. Hence, it appears as if the current set of Applicable Period A on-peak prices may reflect less some other market where parties are actually making real deals and more ComEd's own private conception of where power prices ought to be.

Q. Have you reviewed any historical data pertaining to the Altrade and Bloomberg Powermatch trade prices and/or bid and offer prices?

A. No, I have not reviewed any historical series of data pertaining to Altrade and Bloomberg Powermatch, except for the one-month of data used by ComEd for the actual calculations of MV in this proceeding, i.e., for the initial Applicable Period A. Furthermore, my understanding is that these are relatively new trading platforms, at least for Into-ComEd forward contracts. Hence, there is unlikely to be a significant data series with which to compare the resulting prices with other external benchmarks of price.

Q. Do you have any concerns about the off-peak price data that ComEd proposes to use, namely, "Power Markets Week Daily Price Report"?

A. Yes. These data constitute the midpoint of high and low prices for day-ahead sales of off-peak power, from February 26, 1999 through February 29, 2000. I would prefer to use the weighted average price of trades taking place each day, but these data may not be available. I am concerned that the midpoint of a range can misrepresent the average, if there is any systematic skew in the distribution of prices. From what little analysis I was able to pursue in this regard, however, I have not seen any evidence of a significant bias either upward or downward while using the High-Low midpoints rather than weighted averages.

Q. Have you performed any kind of comparison of the Altrade, Bloomberg Powermatch, and Power Markets Week Daily Price Report data that was provided to other benchmarks for power prices?

A. In this regard, my review has been extremely limited. Unfortunately, the Staff does not maintain any organized database of market price information. I have seen snippets of information on power market prices, but have not had an opportunity or a budget with which to construct or purchase a market price database for power prices.

Q. If not the Staff, to whom should the Commission turn for such information?

A. Buyers and sellers of power. There are several who have intervened in this proceeding. Presumably, the prices in actual deals for power made by these entities would be one benchmark against which to judge the accuracy of the ComEd proposed data sources.

Q. Have you performed any comparisons of the Altrade, Bloomberg Powermatch, and Power Markets Week Daily Price Report price data to the existing NFF's prices?

A. Yes. As I will show later, for on-peak periods, ComEd's proposed alternative MI numbers tend to be significantly higher than the existing NFF numbers during the summer months, but somewhat lower during the remaining months. For off-peak periods, ComEd's proposed alternative MI numbers tend to be somewhat lower than the existing NFF numbers, throughout both the summer and non-summer months.

<u>7.2.</u> <u>*Load-Weighted Adjustment of Prices*</u>

Q. Have you reviewed ComEd's revised method of using PJM-West hourly price data and ComEd class load data in order to compute load-weighted market values?

A. Yes.

Q. Do you believe that the methodology is a reasonable improvement over the currently approved methodology that ComEd uses with the NFF MV input prices?

A. Yes. First, the current methodology is applied only to on-peak prices, while the proposed methodology would be applied to off-peak prices as well. There was never any fundamental reason **not** to apply the current methodology to off-peak prices. Rather, when I originally proposed the methodology in the delivery service proceeding, I expected that the effect would be negligible when applied to off-peak prices. Second, the current methodology first computes averages of hourly prices and hourly loads within each month before performing the hourly load-weighting of market prices. In effect, this initial averaging would tend to dampen the measured effect of any correlation between hourly prices and quantities, which the adjustment is intended to capture. In ComEd's proposal in this case, this dampening effect is removed, which I believe will tend to raise the load-weighted market values for customer classes where there is a positive correlation between their hourly loads and the market prices.

7.3. Comparison of the MI results to the NFF results

Q. How do the MVs computed under ComEd's MI proposal differ from those computed with the current NFF inputs?

A. As can be seen by comparing ComEd Exhibit B, Attachments 4 and 5, the load weighted MVs under the MI are almost everywhere higher than those under the existing NFF-based numbers (with the exception of the Fixture-Included Lighting and Street Lighting Dusk to Dawn classes). This is due to the fact that the MVs from the MI are significantly higher in the summer on-peak period, but somewhat lower during all other periods. A comparison of the proposed MI-based MVs and the existing NFF-based MVs, by rate class, appears in Staff Exhibit 1.2.

Q. How do the CTCs computed under ComEd's MI proposal differ from those computed with the current NFF inputs?

A. In general, the MI-based CTCs of the various CTC rate classes are less than the NFF-based CTCs they would replace. A comparison of the proposed MI-based and the existing NFF-based CTCs, by rate class, appears in Staff Exh. 1.3.

Q. Do all customers benefit from ComEd's proposal?

A. Not necessarily. As developed earlier in this testimony (see Section 4), with a fall in the CTCs, not all customers benefit. This is particularly true for customers that started with a zero or near zero transition charge (under the existing tariffs) and end up with a zero transition charge. For many of these customers, there may not be a significant opportunity for savings by switching to delivery services, and the increase in the MVs under the ComEd proposal may diminish or eliminate their opportunity to reduce their utility bills by switching to the PPO. These are likely to be larger customers. In this regard, Staff asked ComEd to prepare an analysis showing the change in CTC for each of the 3 MW and larger customers (who receive individual CTC calculations rather than class-averaged CTCs) (question 17). That analysis showed that, of the XXX customers with loads in excess of 3 MW that receive individual CTC calculations, XX of them would have a zero CTC under the MI alternative. I would expect that all XX of them would experience an increase in their PPO rate, an expectation that ComEd confirms in another Staff data request (number 18).

For many other customers, the rise in MVs and drop in CTCs brought about by the proposal increase the chance of finding RESs able to provide the customers with savings relative to bundled rates and PPO rates, at least in the near term (between now and January 1, 2001). After the end of the year, new NFF figures would be in effect, and I do not know if the new NFF figures will be above or below the MVs of the proposed MI. The same uncertainty exists next year, and the year after that, etc., until 2006.

7.4. Transition Issues

Q. Do you have any comments on the transition provisions, whereby ComEd would allow existing delivery service and PPO customers to choose between the existing NFF figures and the new MI figures?

A. I have no objection to these provisions. Because of their load characteristics versus that of the average customer in their class, it is certainly possible that some customers would find it advantageous to use the existing NFF MV figures in the PPO. For instance, for customers that receive class-averaged CTCs, there may be a tendency for lower load factor customers (customers with higher peaks relative to average usage) to benefit from the existing NFF figures. Indeed, among customers that have received class-average CTCs, these may be the very same customers who have already switched to the PPO. However, customers with better-than-average load factors, the new MI approach may provide them with an opportunity that does not currently exist to save by switching to delivery services or the PPO. Again, I would hasten to add that while this seems apparent at present, there is certainly no guarantee that such a result will persist in future years within the transition period.

<u>8.</u> <u>Recommendations</u>

Q. Do you recommend that the Commission grant the permission sought by ComEd to place the various original and revised tariff sheets into effect on or shortly after May 1, 2000?

A. Yes, but I would leave room in that recommendation for the Commission to adopt modifications to the ComEd proposal.

Q. Why do you recommend that the Commission grant the permission sought by ComEd?

A. As already noted, I believe that the proposal provides a better opportunity, at least in the short-run, for the average customer to generate some savings by switching to delivery services. Furthermore, ComEd's proposed transition provisions provide existing PPO and delivery service customers with the option of remaining under the existing NFF-based MVs through the end of 2000 or the end of their PPO contract, whichever arrives first.

There is certainly no guarantee that the benefits to average customers of the new MI will persist in future years. However, as a well-known economist once said, "In the long-run, we are all dead." In this case, in the "long-run," the transition period is just six years long. During the transition period, the transition charge can be an extremely effective tool for preventing entry into the market. Waiting for the perfect market index alternative to the NFF may mean waiting until the end of 2006.

Acting at this time to increase MVs could stimulate some additional competitive entry. Additional monitoring and, if necessary, subsequent modifications to, or elimination of, the MI tariffs can be pursued by parties before the Commission. Given the significant concerns with the market index, discussed above, preparing for take such steps would be a prudent precaution.

Q. Have you reviewed Staff witness Christ's recommendation to condition ComEd's continued utilization of Rider PPO (Market Index) on the Company's provision of the wholesale option, discussed in ComEd's petition.

A. Yes.

Q. Does Mr. Christ's recommendation ameliorate the concerns with ComEd's market

index that you discuss in this testimony?

A. Yes. In particular, Mr. Christ's recommendation ameliorates the potential problem of market manipulation and, more generally, provides insurance against underestimated market values computed with ComEd's proposed market index methodology.

Q. On April 13, 2000, Examiner Jones related to the parties several questions from Chairman Mathias. One of those questions was as follows:

> Due to the vagaries of the retail electric market and other considerations, what are the benefits and/or detriments to ComEd recommending to the Commission that this tariff be effective for a defined time period rather than for an indefinite time period? What would be the appropriate defined time period, if any?

Do you have any comments in response to the above question?

A. In essence, the first question asks whether ComEd's proposed tariff sheets (to the extent to which they incorporate an alternative to the NFF) should be subject to a sunset provision, and the second question asks for an appropriate sunset date.

As to when such a sunset might be appropriate, I would note the opposition of several parties (including Commission Staff) to the expedited timetable of this proceeding. A relatively early sunset (such as April 30, 2001) **may** induce ComEd to file a more standard 45-day tariff filing in the near future (or a petition to place revised tariff sheets into effect on May 1, 2001). Hence, the Commission would be afforded an opportunity to consider all the issues surrounding a proposal (such as this) in a more traditional schedule which would allow more time for meaningful and significant discovery, analysis, and development of testimony and legal arguments for or against the proposal and/or modifications to the proposal. On the other hand, there is certainly no guarantee that

ComEd would make such a filing or make it in such a timely manner to allow for significant litigation before the Commission. Thus, the end result of such a sunset may simply be a return to the NFF-based approach on the sunset date or another harried proceeding.

I would also note that a sunset provision is not necessarily the only option for managing the vagaries of the retail electric market. An alternative to a sunset provision would be to rely upon a process whereby a party could petition the Commission to investigate ComEd's tariff or the Commission could open an investigation on its own motion to determine whether the ComEd tariff sheets continue to be just and reasonable. In any event, whether there is an impending sunset date or a pending investigative proceeding, unless there is some other more acceptable market-based alternative waiting in the wings, ComEd would presumably have the right to return to NFF MVs.

Other than providing the above perspectives, I have no recommendation either "for" or "against" a sunset provision.

9. List of the Other Exhibits Accompanying this Testimony

Q. What other exhibits are you sponsoring with this testimony?

A. As referenced in the testimony, I am also sponsoring the following three exhibits:

Exhibit 1.1 - This exhibit is ComEd's response to Staff Data Request 13, showing ComEd's share of the bids and offers in the Altrade dataset proposed to be used for the first Applicable Period A.

Exhibit 1.2 - This exhibit shows the First Applicable Period A alternative market index Market Values compared with the existing NFF-based Market Values.

Exhibit 1.3 - This exhibit shows the First Applicable Period A CTCs under ComEd's proposed alternative market index compared with the CTCs under the existing NFF-based Market Values.

Q. **Does this conclude your testimony?**

A. Yes.

MVs under Proposed MI Compared to MVs under Existing NFF

Rider PPO - Power Purchase Option (Market Index) June 2000 through May 2001

	Summer MVECs			Nonsummer MVECs			
	Peak (cents/kWh)	Off-Peak (cents/kWh)	Non-TOU (cents/kWh)	Peak (cents/kWh)	Off-Peak (cents/kWh)	Non-TOU (cents/kWh)	LWAMV (cents/kWh)
With Only Watt-hour Only	14.330	3.026	9.069	2.923	2.001	2.441	4.529
0 to 25 kW	13.779	2.877	8.617	2.868	1.970	2.415	4.597
Over 25 to 100 kW	14.444	2.969	8.746	2.880	1.949	2.384	4.763
Over 100 to 400 kW	13.497	2.738	8.119	2.825	1.928	2.346	4.382
Over 400 to 800 kW	13.651	2.750	7.987	2.825	1.889	2.304	4.315
Over 800 to 1,000 kW	13.364	2.492	7.882	2.810	1.901	2.339	4.159
Over 1,000 to 3,000 kW	13.119	2.548	7.338	2.766	1.844	2.251	4.123
Over 3,000 to 6,000 kW	13.056	2.570	7.147	2.766	1.838	2.226	3.980
Over 6,000 to 10,000 kW	13.090	2.538	7.139	2.765	1.831	2.229	4.062
Over 10,000 kW	12.427	2.426	6.406	2.700	1.769	2.139	3.633
Fixture-Included Lighting	8.184	1.822	2.938	3.325	1.724	2.099	2.339
Street Lighting - D to D	8.051	1.730	2.839	3.227	1.633	2.006	2.245
Street Lighting - Other	12.305	2.480	6.232	2.762	1.825	2.174	3.530
Railroads	12.860	2.844	7.734	2.703	1.919	2.261	4.119
Pumping	12.705	2.637	6.729	2.832	1.863	2.243	3.864

Rider PPO - Power Purchase Option (Neutral Fact Finder) Mar 21, 2000 - Dec 31, 2000

	Summer MVECs			Nonsummer MVECs			
	Peak (cents/kWh)	Off-Peak (cents/kWh)	Non-TOU (cents/kWh)	Peak (cents/kWh)	Off-Peak (cents/kWh)	Non-TOU (cents/kWh)	LWAMV (cents/kWh)
With Only Watt-hour Only	3.795	3.366	3.564	3.157	3.001	3.069	3.234
0 to 25 kW	3.722	3.316	3.530	3.090	2.947	3.017	3.193
Over 25 to 100 kW	3.717	3.294	3.512	3.075	2.927	2.997	3.181
Over 100 to 400 kW	3.647	3.255	3.451	3.028	2.893	2.955	3.128
Over 400 to 800 kW	3.654	3.249	3.436	3.032	2.885	2.951	3.122
Over 800 to 1,000 kW	3.628	3.234	3.419	3.020	2.874	2.942	3.103
Over 1,000 to 3,000 kW	3.582	3.202	3.372	2.974	2.839	2.899	3.067
Over 3,000 to 6,000 kW	3.576	3.199	3.365	2.974	2.842	2.898	3.062
Over 6,000 to 10,000 kW	3.577	3.202	3.361	2.969	2.838	2.894	3.067
Over 10,000 kW	3.504	3.140	3.282	2.913	2.788	2.837	2.995
Fixture-Included Lighting	3.966	3.421	3.496	3.216	3.040	3.080	3.195
Street Lighting - D to D	3.858	3.324	3.397	3.118	2.945	2.984	3.099
Street Lighting - Other	3.540	3.250	3.358	2.976	2.903	2.930	3.073
Railroads	3.493	3.120	3.310	2.899	2.768	2.830	3.003
Pumping	3.654	3.269	3.422	3.040	2.902	2.957	3.114

DIFFERENCE (Index MV minus NFF MV)

	Summer MVECs			Nonsummer MVECs				
	Peak (cents/kWh)	Off-Peak (cents/kWh)	Non-TOU (cents/kWh)	Peak (cents/kWh)	Off-Peak (cents/kWh)	Non-TOU (cents/kWh)	LWAMV (cents/kWh)	% Increase in LWAMV
With Only Watt-hour Only	10.535	-0.340	5.505	-0.234	-1.000	-0.628	1.295	40.0%
0 to 25 kW	10.057	-0.439	5.087	-0.222	-0.977	-0.602	1.404	44.0%
Over 25 to 100 kW	10.727	-0.325	5.234	-0.195	-0.978	-0.613	1.582	49.7%
Over 100 to 400 kW	9.850	-0.517	4.668	-0.203	-0.965	-0.609	1.254	40.1%
Over 400 to 800 kW	9.997	-0.499	4.551	-0.207	-0.996	-0.647	1.193	38.2%
Over 800 to 1,000 kW	9.736	-0.742	4.463	-0.210	-0.973	-0.603	1.056	34.0%
Over 1,000 to 3,000 kW	9.537	-0.654	3.966	-0.208	-0.995	-0.648	1.056	34.4%
Over 3,000 to 6,000 kW	9.480	-0.629	3.782	-0.208	-1.004	-0.672	0.918	30.0%
Over 6,000 to 10,000 kW	9.513	-0.664	3.778	-0.204	-1.007	-0.665	0.995	32.4%
Over 10,000 kW	8.923	-0.714	3.124	-0.213	-1.019	-0.698	0.638	21.3%
Fixture-Included Lighting	4.218	-1.599	-0.558	0.109	-1.316	-0.981	-0.856	-26.8%
Street Lighting - D to D	4.193	-1.594	-0.558	0.109	-1.312	-0.978	-0.854	-27.6%
Street Lighting - Other	8.765	-0.770	2.874	-0.214	-1.078	-0.756	0.457	14.9%
Railroads	9.367	-0.276	4.424	-0.196	-0.849	-0.569	1.116	37.2%
Pumping	9.051	-0.632	3.307	-0.208	-1.039	-0.714	0.750	24.1%

Docket No. 00-0259
Staff Exh. 1.3

CTCs under Proposed MI Compared to CTCs under Existing NFF

	NFF 3/21/00 -12/31/00	MI 6/1/00 - 5/31/01	NFF-MI	(NFF-MI) as % of NFF
With Only Watt-hour Only Meters	3.999	2.704	1.295	32.4%
0 kW up to and including 25 kW	3.455	2.051	1.404	40.6%
Over 25 kW up to and including 100 kW	2.796	1.214	1.582	56.6%
Over 100 kW up to and including 400 kW	2.338	1.084	1.254	53.6%
Over 400 kW up to and including 800 kW	1.944	0.751	1.193	61.4%
Over 800 kW up to and including 1,000 kW	1.998	0.942	1.056	52.9%
Over 1,000 kW up to and including 3,000 kW	1.778	0.722	1.056	59.4%
Fixture-included Lighting	0.992	1.848	(0.856)	-86.3%
Street Lighting - Dusk to Dawn	-	-	-	
Street Lighting – All Other	1.966	1.509	0.457	23.2%
Railroads	All have individual CTCs			
Pumping	1.603	0.853	0.750	46.8%
Rider 25, Space Heating Service	1.427	0.252	1.175	82.3%
Student Power 2000	2.084	0.866	1.218	58.4%
Student Power 2000 and Rider 25, Space Heating Service	1.150	-	1.150	100.0%
Consolidated Billing Experiment	1.893	0.728	1.165	61.5%
Consolidated Billing Experiment and Rider 25	1.380	0.205	1.175	85.1%
Consolidated Billing Experiment and Student Power 2000	1.804	0.684	1.120	62.1%
Rider GCB, Governmental Consolidated Billing	1.085	-	1.085	100.0%
Rider GCB, Governmental Consolidated Billing and Rider 2	0.746	-	0.746	100.0%